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SCENARIO ANALYSES OF CALIFORNIA'S ELECTRICITY SYSTEM: PRELIMINARY RESULTS FOR THE *2007 INTEGRATED ENERGY POLICY REPORT*

SECOND ADDENDUM

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CHAPTER 1: Background

The California Energy Commission (Energy Commission) staff report *Scenario Analyses of California's Electricity System* (*Results Report*), issued in June 2007, documents a wide-ranging set of results, assumptions, and methods used to assess a series of thematic scenarios emphasizing preferred resource strategies to reduce greenhouse gas (GHG) emissions. Despite a desire to address all planned analyses within the original report, several topics could not be completed in time. Chapter 6 of that report identifies in general terms three topics as forthcoming, including:

- An analysis of the implications of the retirement or replacement of aging power plants located within California
- An analysis of the implications of reducing natural gas consumption for power generation will have on natural gas market clearing prices and, thus, on costs for high penetrations of energy efficiency and renewable generation
- Water consumption for power generation in California and the Rest-of-WECC (Western Electricity Coordinating Council)

This second addendum to the original draft report, prepared for the August 16, 2007, Integrated Energy Policy Report (IEPR) Committee Workshop, is intended to provide an overview of the results for the first two of those topics. Three technical appendices provide the details of these assessments. The third element of analysis, water consumption assessments, is not yet complete and is not addressed in this report.

CHAPTER 2: Retirement and Replacement of Aging Power Plants in California

This section provides an overview of an assessment of the retirement and replacement of aging power plants (Aging) in California. This section provides an understanding of two separate technical analyses:

- An assessment of the need to respond to assumed power plant retirements by developing replacement generating capacity and/or transmission system upgrades
- An assessment of the production cost and other system implications of retirement/replacement assumptions that link to the thematic scenarios under investigation in the overall scenario report.

The discussion in this section is an overview drawing upon more detailed results provided in two appendices to this report. This discussion and the technical appendices will be merged with the preliminary results report when the final version of the *Results Report* is prepared later in 2007.

Previous Examinations of the Aging Power Generation Fleet in California

The Energy Commission began focusing on aging power plants in the *2003 IEPR* with a staff overview report.[1] It conducted an extensive study of aging power plants in California as part of the *2004 IEPR Update*. The focus on these power plants resulted in an examination of how they are used, and the potential vulnerability of the electricity system as a function of certain of the plant's characteristics. The *2005 IEPR* adopted a specific recommendation to encourage procurement policies facilitating aging plant retirement or repowering by 2012:

> The Energy Commission recommends the following to ensure long-term contracts are signed that provide adequate electricity supplies for IOUs:
>
> > The CPUC should require that IOUs procure enough capacity from long-term contracts to both meet their net short positions and allow for the orderly retirement or repowering of aging plants by 2012. (*2005 IEPR*, pp. 64-65.)

Following adoption of the *2005 IEPR*, Energy Commission staff and the transmission planning unit of the California Independent System Operator (California ISO) developed a joint study to devise a methodology for examining the consequences of the *2005 IEPR* policy.[2] The Energy Commission scenario project provided an opportunity to make analytic progress on this topic, albeit through a broad examination of retirement and replacement in the context of the scenario project, rather than through an in-depth development of methodologies to examine particular types of aging power plants.

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[1] CEC (2003), **Aging Power Plants in California**, Staff Paper 700-03-006, July 2003.

[2] California ISO (2007), *2007 Transmission Plan: 2007 through 2016*, p. 91.

Treatment of Aging Power Plants in Preliminary Analyses

In the *Results Report* preliminary analyses, the aging power plants identified in previous Energy Commission studies were retired at 55 years service life. Some power plants reached this benchmark before the 2012 year identified in the *2005 IEPR* policy as the time for retirement, while for others retirement came between 2012 and 2020). A few more plants were not retired by 2020 at all. When the power plants were retired, they were replaced with equivalent dependable capacity to the extent that a simplified resource adequacy protocol required aggregate capacity to satisfy system-wide planning reserve requirements.

Clearly this treatment does not explicitly address the *2005 IEPR* policy, nor does the replacement policy fully reflect the local capacity requirements of resource adequacy that the California Public Utilities Commission (CPUC) added in 2006 for those load serving entities (LSEs) under its jurisdiction.

Previous studies, and recent updates through the end of calendar year 2006, show that the aging power plants run relatively little. Thus, the continuation of aging power plants in the resource mix beyond 2012 contributes little to the projections of overall fuel use and GHG emissions from California power plants. How the aging power plants are replaced would affect fuel use for power generation and imports into California. Should these two factors change in a material way, aggregate GHG emissions from instate power plants and/or California's overall responsibility for electricity sector emissions might be affected in a non-trivial manner.

Because it is uncertain whether, or how, these aging power plants will be retired and their capacity replaced, the scenario project undertook an additional analyses of this topic. This is described in the following section.

Analysis of Aging Power Plant Retirements/Replacements in Southern California

The majority of the aging power plants identified in previous Energy Commission studies are located in the transmission planning area of Southern California Edison (SCE). Staff, assisted by its consultants, undertook a study of the retirement and replacement of these power plants. The study also examined the interactions of retirement, replacement, and changes to the transmission system. This study built upon a joint effort of the Energy Commission staff and the California ISO Transmission Planning unit to examine the implications of retirement of these aging plants on transmission infrastructure.[3]

Approach

The retirement/replacement project was conducted in two steps. First, a group of aging power plants located in the SCE service area were identified as likely retirement candidates. These plants totaled 4,140 MW of capacity. Assuming retirements occurred in year 2012, a set of replacement capacity was identified that satisfied a simplified version of local capacity requirements (LCR) allowing for changes in the transmission

[3] The joint effort was interrupted before completing its original scope of work due to the staffing needs of the Energy Commission for the *2007 IEPR* and of the California ISO for the *2008 Local Capacity Requirements* study submitted to the CPUC in March 2007.

infrastructure.[4] Transmission system contingency assessments identified overloaded transmission lines and suggested mitigation measures for the transmission system through time. This set of replacements and corresponding transmission infrastructure upgrades were customized to each of the previous scenario cases 1B (Current Requirements), 3A (High Instate Energy Efficiency), and 4A (High Instate Renewables). [5]This set of retirements, replacement capacity, and transmission system upgrades were used to guide changes in the production cost model input dataset, and Multisym was rerun. The scorecard process was also rerun to allow in-depth comparison of the preliminary results with these new sets of runs for the same scenarios.

After examining the initial results, a similar set of retirements, replacements, and transmission system upgrades were identified that linked retirement and replacement with the underlying development of energy efficiency program savings or renewable generation development in each of the three cases previously reported in the *Results Report*. In general, this was a slower pace of retirements compared with assuming mass retirement in 2012, but it had the benefit of linking replacements with unconventional generating resource development patterns and partially deferring transmission upgrades. As before, this second set of alternative retirement, replacement, and transmission system changes was used to develop Multisym production cost model datasets, and these were run to allow comparisons with previous results.

Two overview comments set the stage for the specific analytic work that was undertaken. First, numerous alternative ways exist to link retirements with replacement capacity or transmission system upgrades. Slowing down retirement and replacement to match the development of energy efficiency program savings or renewable generating development as previously configured in Cases 1B, 3A, or 4A allowed comparability with the previous scenario project cases. Given more time, perhaps the underlying scenario cases could have been modified to accelerate the development of energy efficiency program savings or the renewable generating facilities to better match mass retirement in 2012. Because such acceleration was not considered, whether it is feasible was not assessed. As noted previously, the scenario project cases are not optimized, but were examined with a set of "what if?" assumptions. Better linking replacement with retirements, as this assessment has done, is only a modest step in the direction toward optimization. Second, supporting Appendix 1 of Appendix A identifies that full retirement of the entire Aging Plant fleet in the SCE transarea was examined, but that it was not examined in the same level of detail as this partial set of retirements once it was determined that the transmission system upgrades required were much more extensive.[6] For this initial examination of retirements, staff focused on a subset that encompasses the majority of the capacity considered Aging.

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[4] The near term local capacity requirement studies conducted by the CAISO for resource adequacy compliance years 2007 or 2008 include minimal changes to the transmission system that would affect resulting capacity requirements since the time horizon of one year is so short.

[5] Time and resources did not permit examination of this topic for Case 5A (high energy efficiency and high renewable generation).

[6] A transarea is a geographic region used in production cost modeling. It is the basic unit for load forecasts and generally assumes no internal transmission limitations for generation from power plants located therein to serve load. Figure 5-1 of the *Results Report* identifies the 29 transareas making up the entire Western Interconnection as it was modeled for this project.

Overview of Retirement/Replacement Alternative Cases

This section provides a tabular comparison of the original preliminary retirements and the two sets of accelerated retirement/replacement assumptions. The two new sets of assessments are referred to as policy-directed retirement/replacement cases, in contrast to the original assessments that retired plants at year 55 of their service life. The detailed assessment is found in Appendix A.

Table 1 compares aging power plant and replacement capacity for the nine cases. Three of these are contained in the *Results Report*, while six of them are reported here for the first time. This table is organized as three groups of rows, one for each of the thematic scenarios. The table has three columns of data that report the version of the capacity assumptions. The three rows and three columns of data provide nine sets of information. Each set consists of the following items:

- Aging power plant capacity still on line in each of the three future years
- New combustion turbine capacity in the transarea
- New combined cycle capacity in either the SCE transarea or the Southern Nevada transarea

Table 1: Thermal Capacity Retirement and Replacement in the SCE Transarea (MW)

	Original Analysis			2012 Retirement			Phased Retirement		
	2012	2016	2020	2012	2016	2020	2012	2016	2020
Case 1B (Current Req.)									
Total Aged Plants Online	6,325	5,111	2,991	2,510	2,510	2,510	3,110	2,510	2,510
New Peaking Capacity	-	-	-	2,802	2,801	3,144	2,800	3,002	3,146
New Combined Cycle Capacity	-	-	-	3,688	3,688	3,688	3,138	3,138	3,688
Total New Thermal	-	-	-	6,490	6,489	6,832	5,938	6,140	6,834
Case 3A (High Eficiency)									
Total Aged Plants Online	6,325	5,111	2,991	2,510	2,510	2,510	3,110	2,510	2,510
New Peaking Capacity	-	-	-	3,010	3,010	2,750	3,010	3,010	3,141
New Combined Cycle Capacity	-	-	-	3,138	3,138	3,138	2,568	2,568	2,568
Total New Thermal	-	-	-	6,148	6,148	5,888	5,578	5,578	5,709
Case 4A (High Renewable)									
Total Aged Plants Online	6,325	5,111	2,991	2,510	2,510	2,510	4,330	2,710	2,510
New Peaking Capacity	-	-	-	3,305	3,305	3,045	2,810	3,002	2,742
New Combined Cycle Capacity	-	-	-	3,138	3,138	3,138	1,870	1,870	1,870

Note: The capacity reported under the Original Analysis reflects nameplate capacity, and the capacity reported under 2012 Retirement and Phased Retirement reflects a summer derate due to ambient temperatures.

Source: Navigant Consulting

A portion of all three assessments are identical in the column labeled "Original Analyses." In the original work, since retirements took place according to plant service life, there will be no differences among Cases 1B, 3A, and 4A. There was no thermal replacement capacity, because the simplified resource adequacy protocols did not have an LCR feature. In contrast, the two sets of policy-directed retirement assessments result in substantial levels of new, relatively efficient generating capacity that replaces old, inefficient capacity. In the "2012" columns, all retirements take place in 2012, and all replacement for retired capacity becomes operational in 2012. Capacity does not change for 2016 or 2020. In the "Phased" columns, retirements and corresponding replacements occur beginning in 2012, but retirements reach the level of the "2012" case as development of the preferred resources permit. Further, the amount of thermal replacement capacity is different in the "Phased" column because the resources added to the resource plan, in keeping with the theme of the scenario, have different capacity implications, and therefore, the thermal capacity needed in addition to the thematic resources is not equal across the three scenarios.

Comparing the three thematic scenarios, the Case 3A analysis and the Case 4A analysis have less thermal capacity additions than does Case 1B. Case 3A has less because net load after the incremental energy efficiency savings are subtracted requires fewer total resources to meet lower load. Case 4A is less than Case 1B because renewable development in conjunction with specific transmission system upgrades, supports a portion of the LCR needs and diminishes the amount of new thermal capacity that must be developed.[7] To be specific, in the potential tradeoff between generation additions and transmission system additions, this analysis has chosen to assume some specific transmission system changes that have been evaluated through power flow assessments.

The thermal resources added as replacement capacity were drawn from two sources to ensure that bus-level information would be available to allow a power flow assessment. One source was power plants already licensed by the Energy Commission, but not included in prior assessments as "named additions." The second is the California ISO generator interconnection queue. While selecting plants from these two sources is no assurance such plants will actually be built, by doing so this allows an assessment to be conducted using the likely candidates and facilitates realistic transmission assessments.

Despite quite different methodological approaches to handling retirements and replacements between this analysis and the original analysis reported in the *Results Report*, the 2020 level of aged power plants still operational is not very different. The 55 year service life rule managed to retire almost as much capacity as the two policy-directed assessments reported here. Of course the replacement capacity identified to satisfy local capacity requirements is very different.

Table 2 identifies the transmission system upgrades and/or mitigation measures and their costs for the nine cases. Table 2 is organized in three vintages of analysis as was Table 1, but under each vintage are the three thematic scenarios. Thus the nine cases are nine columns (three groups of three), while the rows are the years in which transmissions

[7] Changing LCR values through time as a result of changes in the type of resource mix and the nature of the transmission system have not yet been submitted to the CPUC by California ISO as part of LCR assessments because the formal requirement for LCR is for a time horizon only one year ahead. For such a short period, resource mixes cannot change in any appreciable way, and only very limited changes to the transmission system are possible. In the far-forward time horizon of this analysis, many more changes can, and must, be addressed. This topic will be encountered in workshop discussions in CPUC R.05-12-013 when parties address the implications of multi-year forward resource adequacy designs.

upgrades or mitigation measures are required. Table 2 augments the information discussed in the *Results Report*, because the focus of the aging power plant retirement/replacement analysis is on transmission implications internal to the SCE transarea, not transfer capability changes between transareas.

One of the largest transmission system upgrades reported in Table 2—the seven segments of the Tehachapi transmission line—could arguably be classified differently than is reported here.[8] Table 2 assigns all seven segments to Case 1B, and there are no incremental costs for Case 4A. Alternatively, one could argue that the wind development in the Tehachapi region in Case 1B could be supported by something less than the full seven line segments, and Case 4A with its increased wind development ought to carry some of the last segments that will be developed.

Like the generation assessment reported in Table 1, Table 2 identifies substantially more modifications for the 2012 Retirement and the Phased Retirement columns than is reported for the original assessment columns. The local capacity requirements analysis conducted and reported here addresses a facet of transmission system development that was simply not done for the initial work of this project. Further, it has not yet even been applied to all of California, since the transmission systems of Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Los Angeles Department of Water and Power (LADWP) may well have their own upgrades necessary and/or desirable to facilitate retirement of aged power plants in those service areas.

This discussion has provided a broad overview of the transmission assessment results, while Appendix A identifies the details of the transmission system analysis.

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[8] Some segments are apparently necessary to support expected load growth irrespective of wind development, and such costs ought to have been assigned to Case 1, rather than any of the policy preference cases.

Table 2: Transmission System Upgrades and Installed Costs Associated with Aging Power Plant Retirement and Replacement in the SCE Transarea Under Alternative Resource Development Strategies (Millions of $2007)

Project Timing	Identified Upgrades or Modifications	Original Assessment			2012 Retirement Policy			Phased Retirement Policy		
		1B	3A	4A	1B	3A	4A	1B	3A	4A
2012 Additions										
Tehachapi Renewable Transmission Project [1]	Segments 1, 2, 3, 4, 5, 9 and 10 of the proposed T-line	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0
Pisgah-LA Basin Upgrades	1000MW upgrade consisting of expansion of the Lugo 500/230-kV substation; new 500/230-kV substation at Pisgah; new 500-kV line between Pisgah and Lugo; and looping the existing El Dorado-Lugo in and out of the new Pisgah 500-kV substation	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Chino-Mira Loma #1 and #3	Rebuild #1 Line; add line and transformer terminations at Chino; and add line termination at Mira Loma				36.4	36.4	36.4	36.4	36.4	36.4

Project Timing	Identified Upgrades or Modifications	Original Assessment			2012 Retirement Policy			Phased Retirement Policy		
		1B	3A	4A	1B	3A	4A	1B	3A	4A
Barre-Ellis Upgrades [2]	Rebuild and reconductor section of line; replace switches at Barre and Ellis; and replace wave traps at Barre and Ellis				28.9	28.9	28.9			
Moorpark-Pardee Upgrades	Replace switches at Moorpark and Pardee; and replace wave traps at Morrpark and Pardee				3.2	3.2	3.2	3.2	3.2	3.2
La Fresa-Redondo Upgrades	Remove wave traps				140.0	140.0	140.0	140.0	140.0	140.0
2012 Total		1,700.0	1,700.0	1,700.0	1,908.5	1,908.5	1,908.5	1,879.6	1,879.6	1,879.6
2013 Additions										
Barre-Ellis Upgrades [2]	Rebuild and reconductor section of line; replace switches at Barre and Ellis; and replace wave traps at Barre and Ellis							28.9	28.9	
2013 Total		0.0	0.0	0.0	0.0	0.0	0.0	28.9	28.9	0.0
2016 Additions										

Project Timing	Identified Upgrades or Modifications	Original Assessment			2012 Retirement Policy			Phased Retirement Policy		
		1B	3A	4A	1B	3A	4A	1B	3A	4A
SCE 230-kV grid - addition of shunt capacitors	Add 379 MVAR banks with breakers				10.8	10.8	10.8	10.8	10.8	10.8
2016 Total		0.0	0.0	0.0	10.8	10.8	10.8	10.8	10.8	10.8
2017 Additions										
Barre-Ellis Upgrades [2]	Rebuild and reconductor section of line; replace switches at Barre and Ellis; and replace wave traps at Barre and Ellis									28.9
Pisgah-LA Basin Upgrades	Additional 1000MW upgrade consisting of new 500-kV switchyard near Lugo; second new 500-kV line between Pisgah and Lugo; and additions to the system south of the Vincent Substation			500.0			500.0			500.0
2017 Total		0.0	0.0	500.0	0.0	0.0	500.0	0.0	0.0	528.9
2020 Additions										

Project Timing	Identified Upgrades or Modifications	Original Assessment			2012 Retirement Policy			Phased Retirement Policy		
		1B	3A	4A	1B	3A	4A	1B	3A	4A
Pardee	Develop new 500/230-kV Substation at Pardee				92.6	92.6	92.6	92.6	92.6	92.6
Vincent	Add 500-kV line termination at Vincent				6.3	6.3	6.3	6.3	6.3	6.3
SCE 230-kV grid - addition of shunt capacitors	Add 379 MVAR banks with breakers				10.8	10.8	10.8	10.8	10.8	10.8
2020 Total		0.0	0.0	0.0	109.7	109.7	109.7	109.7	109.7	109.7
Total For All Years		1,700.0	1,700.0	2,200.0	2,029.0	2,029.0	2,529.0	2,029.0	2,029.0	2,529.0

Note 1: Per the CPUC workshop documents dated November 21, 2006, Tehachapi segments 6, 7, 8, and 11 would be required to meet load growth in the Los Angeles area and would be built even if the Tehachapi project is not built. The costs for these segments are assumed in all cases and are excluded from this table. Only transmission costs that differed between the scenarios are captured in the analysis.

Note 2: The Barre-Ellis upgrade could be deferred past 2012 if the retirement of Huntington Beach Units 1 and 2 are deferred, or the upgrade could be avoided if these units remain on line or are replaced by capacity at or near Huntington Beach.

Production Cost Model Results

This section provides an overview of the production cost model results and how these compare to the preliminary cases reported in the June report. A more detailed assessment, including the two-zone "scorecards," providing in-depth results comparable to those of the *Results Report* is found in Appendix B.

Once the capacity retirement and replacement schedules summarized in Table 1 were established, Global modified the Multisym production cost model datasets. The retirement of each aged power plant included in Table 1 changed from its original 55-year service life to match the assumptions of either of the two policy-directed retirement cases. New thermal capacity was added to the dataset as summarized by Table 1. The modified production cost datasets were then run to determine the results.

Table 3 compares energy generated by several groups of power plants in the SCE transarea for the nine cases. Table 3 is organized in the same manner as Table 1; that is, there are three sets of columns and three sets of rows comparable to the two previous tables. Each "cell" of this three-by-three matrix provides summary information for that case to all comparisons across these cases. Unlike Table 1, Table 3's middle and right-hand columns show the differences from the original projections for each of the two sets of policy-directed retirements. The obvious and expected result in each of the two policy-directed sets of cases is that gas-fired generation within the SCE transarea increases substantially. In the earlier years, the increase is virtually the same magnitude, that is, about 35 percent more than in the original case. By 2020, however, the three thematic scenarios are differentiated from one another, and the increases are somewhat different. For Case 1B, there is very little difference between the 2012 retirement and the phased retirement cases in terms of natural gas generation increase. Case 3A shows less growth than Case 1B, and there is a modest difference between the two replacement scenarios. For Case 4A, the generation from the new facilities actually decreases through time, and there is considerable difference between the variants of Case 4A analysis. There are negligible changes for generation of other fuel types given the dominating role of gas-fired facilities as swing resources.

Table 3: Generation (GWh) by Fuel Type in SCE Transarea

Generation(GWh) by Fuel Type	Original Assessment			Difference Between 2012 Retirement Policy and Original Assessment			Difference Between Phased Retirement and Original Assessment		
	2012	2016	2020	2012	2016	2020	2012	2016	2020
Case 1B									
Natural Gas	33,097	30,490	32,690	11,857	11,973	14,064	12,570	12,730	14,148
Nuclear	15,879	15,274	16,828	32	(16)	(28)	-	(16)	(28)
Petroleum Coke	117	145	203	(10)	(17)	(2)	(10)	(14)	(3)
Pumped Storage	436	433	473	6	(1)	(12)	6	(8)	1
All Other Generation	21,156	26,860	27,543	-	-	-	-	-	-
Total	70,686	73,203	77,736	11,884	11,940	14,021	12,566	12,693	14,118
Case 3A									
Natural Gas	32,574	29,243	30,819	11,874	11,446	12,515	10,309	9,829	11,074
Nuclear	15,879	15,274	16,828	32	(16)	(28)	-	(16)	(28)
Petroleum Coke	117	141	200	(12)	(14)	(2)	(8)	(14)	(2)
Pumped Storage	432	408	431	2	2	19	(5)	15	14
All Other Generation	21,156	26,860	27,543	-	-	-	-	-	-
Total	70,158	71,926	75,821	11,896	11,419	12,504	10,295	9,815	11,058
Case 4A									
Natural Gas	32,706	27,458	26,093	11,913	9,268	9,195	8,252	6,828	6,176
Nuclear	15,879	15,274	16,828	32	(16)	(28)	-	(16)	(28)
Petroleum Coke	118	129	189	(10)	(4)	(1)	(8)	(2)	(1)
Pumped Storage	429	416	441	1	1	1	2	0	(2)
All Other Generation	24,889	41,001	55,044	-	-	-	-	-	-
Total	74,021	84,278	98,595	11,937	9,250	9,167	8,246	6,811	6,145

Table 4 is again organized as a "matrix" with three rows and three columns. However, the three primary groups of rows are different variables, and the analysis of the three thematic cases becomes the secondary row headings. The three versions of retirement/replacement analysis are shown in the same manner as in Table 3. Table 4 shows that the increase in generation in gas-fired generation within the SCE transarea is offset by a similar decrease in net imports. Net imports are calculated as imports into the SCE transarea, less exports out of SCE. A more detailed examination of imports and exports within the SCE transarea shows that imports into the SCE transarea decline and exports from the SCE transarea increase. Part of the increased thermal generating capacity within the SCE transarea is exported out of the area, while the rest is offset by fewer imports. With a substantial fleet of new, efficient generators this can be expected. The efficient generators displace older, less efficient generation, both within the SCE transareas and elsewhere in the West. Perhaps less intuitively, imports into California as a whole decline. Correspondingly, gas-fired generation in the Rest-of-WECC declines slightly in all three thematic scenarios.

Table 5 shows annual average capacity factors for generation within the SCE transarea. Table 5 is organized in the same style as Table 3, but shows predicted capacity factors for certain groups of plants. The new combined cycle and peaking plants displace the older combined cycle plants. Although the Phased Retirement version of Scenario 4A was intended to create a better fit with the renewable capacity coming on line throughout the period up to 2020, capacity factors of the new combustion turbines decline through time. This may indicate that a greater weighting toward simple cycle peakers and less toward combined cycles would be preferred than the mix that was evaluated.

The basic conclusion is that both the versions of policy-directed retirements and the replacement thermal additions generate more electricity in the SCE transarea than in the original case for all three thematic scenarios.

Table 4: Imports into and Exports Out of the SCE Transarea (GWh)

	Original Assessment			Difference Between 12 Retirement Policy and Original Assessment			Difference Between Phased Retirement and Original Assessment		
	2012	2016	2020	2012	2016	2020	2012	2016	202
Net Imports into SCE									
Case 1B	37,747	36,452	34,233	(11,877)	(11,941)	(14,037)	(12,558)	(12,703)	(14,117)
Case 3A	37,071	34,709	30,789	(11,894)	(11,416)	(12,480)	(10,303)	(9,795)	(11,041
Case 4A	38,509	33,023	23,963	(11,935)	(9,248)	(9,166)	(8,244)	(6,810)	(6,148)
Imports into SCE									
Case 1B	46,375	44,591	44,221	(7,594)	(7,996)	(9,217)	(8,241)	(8,765)	(9,072
Case 3A	45,506	42,667	40,658	(7,687)	(7,989)	(8,167)	(6,866)	(6,951)	(7,190
Case 4A	46,368	39,551	35,314	(7,914)	(6,944)	(6,100)	(5,394)	(5,189)	(4,222
Exports out of SCE									
Case 1B	8,628	8,139	9,988	4,283	3,945	4,820	4,317	3,938	5,045
Case 3A	8,435	7,958	9,869	4,207	3,427	4,313	3,437	2,844	3,851
Case 4A	7,859	6,528	11,351	4,021	2,304	3,066	2,850	1,621	1,926

Note: Net Imports are calculated as imports into SCE less exports out of SCE.

Table 5: Annual Average Capacity Factor (%) in SCE Transarea

Annual Average Capacity Factor	Original Assessment			Difference Between 2012 Retirement Policy and Original Assessment			Difference Between Phased Retirement and Original Assessment		
	2012	2016	2020	2012	2016	2020	2012	2016	2020
Case 1B									
New-CC	0%	0%	0%	60%	59%	67%	59%	60%	66%
New-GT	0%	0%	0%	6%	2%	2%	6%	4%	3%
Old-CC	40%	38%	42%	-8%	-10%	-10%	-9%	-10%	-10%
Old-ST	4%	0%	2%	-4%	0%	-2%	0%	0%	-2%
Case 3A									
New-CC	0%	0%	0%	59%	57%	63%	59%	58%	64%
New-GT	0%	0%	0%	6%	3%	1%	5%	2%	1%
Old-CC	39%	35%	38%	-8%	-10%	-10%	-8%	-8%	-8%
Old-ST	4%	0%	1%	-4%	0%	-1%	0%	0%	-1%
Case 4A									
New-CC	0%	0%	0%	59%	48%	46%	62%	51%	50%
New-GT	0%	0%	0%	4%	3%	3%	6%	3%	3%
Old-CC	39%	32%	29%	-8%	-10%	-8%	-6%	-7%	-6%
Old-ST	4%	0%	0%	-4%	0%	0%	-1%	2%	0%

Note:

CC = combined cycle, GT = simple cycle combustion turbines, ST = steam boiler.

New = resource added in year 2011 or later.

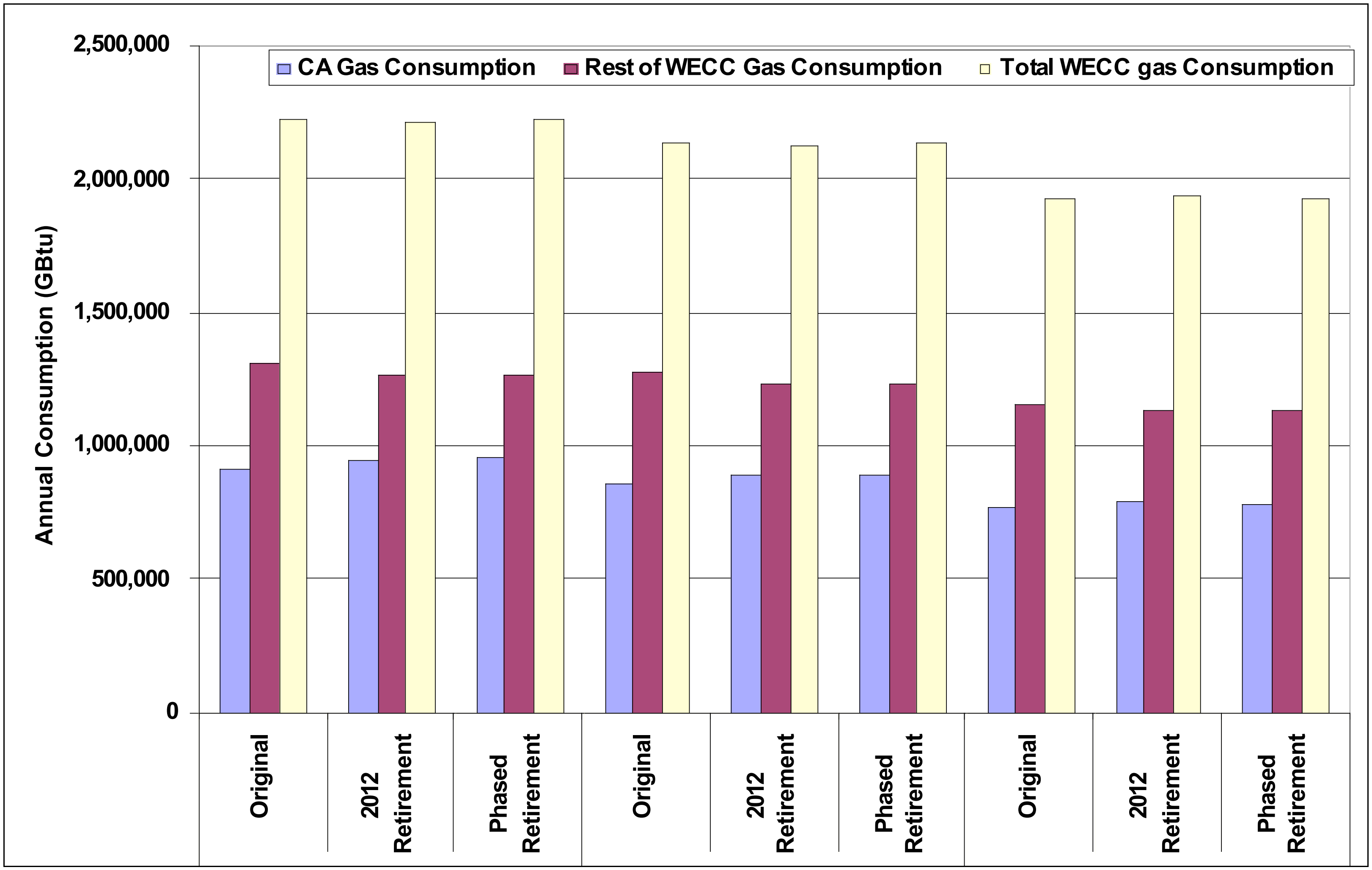
Old = existing resources in 2006 or those added prior to year 2011.

Figure 1 plots the change in natural gas consumption for California, Rest-of-WECC, and Total WECC. The same pattern that existed for the original analysis between thematic scenarios is preserved in the new assessments. However, in each thematic case, the two policy-directed assessments show greater California use of natural gas, lower Rest-of-WECC use of natural gas, and virtually unchanged West-wide use of natural gas for power generation. This indicates that import changes are almost entirely from natural gas units. So in the policy-directed assessment, California use of natural gas substitutes for Rest-of-WECC use of natural gas for power generation.

Table 6 compares GHG emissions (carbon dioxide only) in California and Rest-of-WECC for the nine cases. Table 6 follows the same convention as the previous three tables and compares the new assessments with the original assessments in the form of a three-by-three matrix. The two right-hand columns show the differences between the original assessment and the two policy-directed assessments. In Case 1B, California generation emissions increase, but California responsibility (instate generation, remote power plants, and imports) decreases. Rest-of-WECC carbon dioxide emissions also increase very slightly. In Case 3A and Case 4A, the same results occur as well. The increase in California generation results in a decrease in imports. The power plants supporting the higher imports of the original assessments are used in Rest-of-WECC, leading to slightly higher emissions in Rest-of-WECC. Once again, the role of imports and the least cost dispatch method of analysis shift the result in ways that are difficult to predict without using the model.

Table 7 reports levelized system costs in the same style as Table 6. The results are also similar to earlier variables in that there are only very slight changes for the policy-directed cases compared with the original assessment. In Cases 1B and 3A, the two policy-directed retirement cases are slightly lower than the original assessment. In Case 4A, the two policy-directed cases are slightly higher than the original assessment.

Figure 1: Change in Natural Gas Consumption for Power Generation in 2020



Source: Global Energy

Table 6: Predicted GHG Emissions for California and Rest-of-WECC (Thousand tons of carbon dioxide per year)

Annual CO2 (1000 tons)	Original	2012 Retirement	Phased Retirement	Difference between 2012 Retirement and Original Case	Difference between Phased Retirement and Original Case
Case 1B			**2020**		
California Production	63,907	65,629	65,677	1,721	1,770
California Remote Generation	27,087	27,023	27,003	(64)	(84)
California Imports	16,982	14,017	14,072	(2,965)	(2,910)
Total California Responsibility	107,976	106,668	106,752	(1,308)	(1,223)
Rest-of-WECC Production	354,757	355,503	355,494	746	736
Rest-of-WECC Remote Generation	36,294	36,209	36,177	(85)	(117)
Total Rest-of-WECC	391,051	391,712	391,671	661	620
			2020		
Case 3A					
California Production	60,032	62,071	61,749	2,040	1,717
California Remote Generation	27,048	26,957	26,962	(91)	(87)
California Imports	14,572	11,503	11,888	(3,068)	(2,684)
Total California Responsibility	101,652	100,532	100,599	(1,120)	(1,053)
Rest-of-WECC Production	355,389	356,319	356,306	929	916
Rest-of-WECC Remote Generation	36,247	36,123	36,093	(124)	(154)
Total Rest-of-WECC	391,637	392,442	392,399	806	762
			2020		
Case 4A					
California Production	58,078	59,681	59,063	1,603	985
California Remote Generation	26,843	26,756	26,800	(87)	(43)
California Imports	4,970	2,829	3,554	(2,140)	(1,416)
Total California Responsibility	89,891	89,267	89,416	(624)	(474)
Rest-of-WECC Production	357,924	358,601	358,275	676	351
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Source: Global Energy

Table 7: Levelized System Costs ($2006/MWh)

Levelized Total System Costs ($/MWh)	Original	2012 Retirement	Phased Retirement	Difference between 2012 Retirement and Original Case	Difference between Phased Retirement and Original Case
Case 1B					
California	46.38	48.03	48.10	1.65	1.72
Rest-of-WECC	29.31	29.19	29.12	(0.12)	(0.19)
Total WECC	34.67	35.09	35.06	0.42	0.39
Case 3A					
California	46.67	48.43	48.31	1.75	1.64
Rest-of-WECC	29.20	29.01	29.04	(0.20)	(0.16)
Total WECC	34.63	35.01	35.00	0.39	0.38
Case 4A					
California	51.19	53.10	52.69	1.90	1.49
Rest-of-WECC	29.15	28.97	29.04	(0.18)	(0.11)

Source: Global Energy

Note: the annual system costs are levelized between 2009 through 2020 using a discount rate of 8.61%.

Implications of the Results

The analysis of aging power plant retirement and replacements documented here should not be considered merely an alternative to the original analysis underlying the June 2007 *Results Report*. That effort was unable to incorporate this work simply due to the timing of the analytic effort. The 2012 Retirement case within the 1B, 3A, and 4A thematic scenarios reflects the policy established in the *2005 IEPR*. To the extent that detailed analysis supports an alternative to that policy, it is a phased retirement rather than the simple 55-year service life retirement that was the basis for the original analysis.

This analysis has shown that a combination of preferred and conventional resources are most likely necessary to implement the aging power plant retirement policy in the context of large penetrations of preferred resources. The local capacity requirements now established for the California ISO control area, through a combination of California ISO tariff and CPUC decisions, suggest that capacity in local areas cannot be fully satisfied by energy efficiency savings or renewable resources. Changes to the transmission system can reduce the amount of conventional resources that are needed by allowing greater reliance upon renewable resources. The magnitude of this effect needs further analysis.

The energy efficiency savings, renewable generation, and transmission system changes explored in this analysis have not yet been systematically examined by the California ISO or by SCE, the local transmission operator. Discussions were held with each of these entities at a few points during the period of this analysis, and their recommendations, based on limited review opportunities, led to changes in the analysis that have been reflected herein. This advance involvement should not be considered an endorsement of these technical results. Staff considers this effort to be only an initial step in the direction of assessing the implications of the aging power plant retirement/replacement policy of the *2005 IEPR*. Staff aspires to further efforts, especially in collaboration with these two entities, as well as others.

Like other aspects of this overall scenario project, policy makers should note numerous limitations. First, this analysis only examines the implications of retiring and replacing broad groups of power plants, and these do not amount to the total aged power plant capacity in the SCE service area. No work has been conducted to examine which specific plants qualify for treatment called for by SB 1576 (Nuñez, Chapter 374, Statutes of 2005). Second, the transmission line contingency assessment is a rough approximation to the analysis to which the California ISO subjects the transmission system when it conducts its local capacity requirements studies. It is unclear whether the sets of contingencies the California ISO examines might identify other overloads leading to additional costs of upgrades to the SCE transmission system. Third, this analysis only addresses retirement of aged power plants in the SCE service area. Power plants in the PG&E, SDG&E, and LADWP service areas have not been examined in this effort. Finally, the massive retirement and replacement, and the associated transmission system upgrades postulated here, have practical, implementation problems that have not been studied in depth. It is not obvious that a single entity has control over enough players in the industry to make such a large change in the system happen in the timeframes assessed. Therefore, a serious effort to identify a coordination mechanism that could plan for, and manage, such an overall effort should be undertaken in concert with further analytic efforts to refine this initial study.

CHAPTER 3 - Natural Gas Market Clearing Price Implications of Reduced Consumption from the Power Generation Sector

This section provides an overview of the implications on natural gas market clearing prices of reduced consumption of natural gas by the power generation sector as predicted in some of the thematic scenarios investigated in this project. As previously described in the *Results Report*, the West-wide, high efficiency, high renewables scenario (Case 5B) provides a major reduction in annual consumption of natural gas compared with the two cases reflecting current expectations (Case 1, Current Conditions, and Case 1B, Current Requirements). The analysis described here answers the question, "What might happen to market clearing natural gas prices compared to the illustrative base case (IBC) if the scenario low consumption Case 5B were to occur?"[9]

The discussion in this section is an overview drawing upon more detailed results provided in a technical appendix to this report – Appendix C. This discussion and the technical appendix will be merged with the preliminary *Results Report* when the final version of the report is prepared later in 2007. In addition, Global Energy prepared Appendix D, which provides some suggestions for further work on natural gas implications for the complete scope of the scenario project.

Fuel Price Projections in the Scenario Project

The fuel price projections used for the analyses documented in the *Results Report* are described in Chapter 5 and Appendices H-1 through H-4 of that report. The fuel prices documented there were used for all baseline variants of the scenarios and all sensitivity cases except those explicitly designed to test fuel price sensitivity. Although the various scenarios including increasingly large amounts of preferred resources have the effect of reducing natural gas consumption compared to scenarios relying upon conventional fossil generating technologies, prices were assumed to be the same as developed for the IBC price projections.

Figure 2 duplicates a figure from the *Results Report* that provides the IBC baseline natural gas price projections through 2020 as well as the P25 and P75 alternatives to the IBC that were used in the fuel price sensitivity assessments. Figure 2 shows that the entire set of price projections have a slow upward trend somewhat obscured by cyclic variations.

Analysis of the Implication of Low Power Plant Usage on Natural Gas Prices

This subproject was designed to address the question of whether high penetration of preferred resources would decrease consumption of natural gas to a sufficient degree to induce market price changes. A CPUC-sponsored study by the Center for Resource

[9] "Illustrative Base Case" (IBC) is the term Global Energy uses for the natural gas price projections developed for use as the baseline natural gas prices for the scenario project. Appendix H-2 of the *Results Report* provides a description of the process Global used to prepare this set of projections. Although the power generation natural gas demand used by the Global gas team in the IBC was not precisely the same as that developed in Case 1 by the Global electric team, it was considered close enough that differences were ignored in this subproject.

Solutions found such an effect when examining the implications of large penetrations of renewable generating technologies.[10] In another study, Wiser et al. surveyed a large number of energy efficiency and renewables studies, examining the natural gas price reduction consequences of these preferred energy resources.[11] The analysis of this project focused upon the West-wide cases from the beginning, since it was believed that changes in power generation natural gas consumption from California alone would not be large enough to have any noticeable effect.

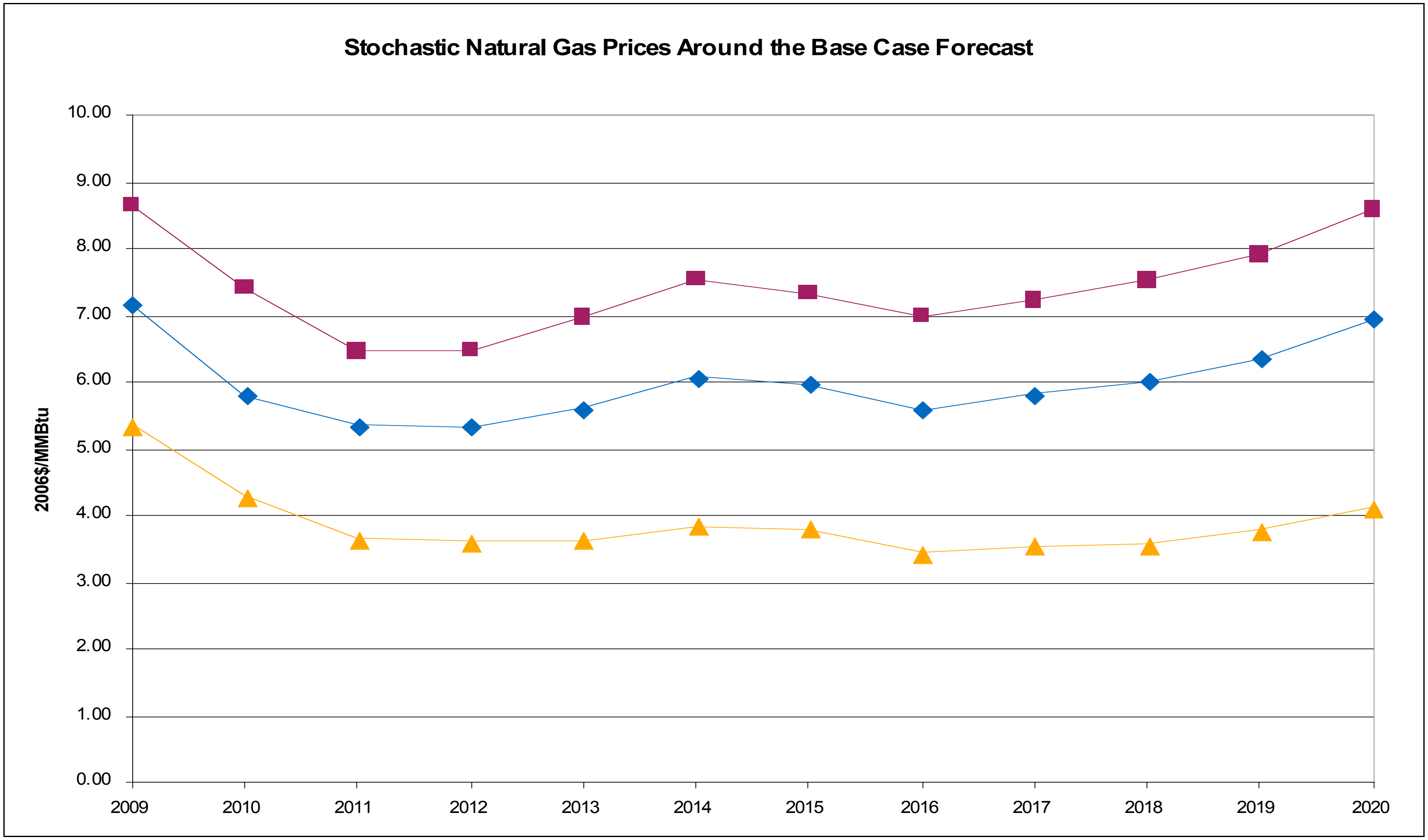
Approach

This section provides a broad overview of a detailed description of work attached as Appendix H-5. That appendix not only provides the final results, but a step-by-step description of the process Global used to arrive at the final results.

The scale of the effect is obviously important. As noted previously, this project assumed that reductions in California demand alone would be insufficient. In order to develop a methodology, the project team evaluated Case 3B (West-wide high energy efficiency) since its results were available early in the project. Case 3B implies a reduction in West-wide natural gas demand for power generation gradually rising to about 39 percent in 2020 compared to the IBC assumptions. This is equivalent to about 17 percent of total West-wide natural gas demand. This is also equivalent to about 2.5 percent reduction in total expected natural gas demand in North America.[12] Inserting this level of demand reduction into the western portion of the forecasting model and rerunning the model reduced market clearing prices measured at Henry Hub by about 19 percent. This implies that the marginal cost, or marginal price of the last unit of gas produced to satisfy the market, is extremely high, so that a relatively small change in North American demand creates a large reduction in market clearing price.

[10] Center for Resource Solutions (2005), under contract to the CPUC, *Achieving a 33 Percent Renewables Target*, Chapter 4.
[11] Wiser, R. (2005), *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency*, LBNL-56756.
[12] Global assumes that natural gas for power generation remains at the same general percent of total natural gas demand as it has for the past several years.

Figure 2: Stochastic Natural Gas Prices ($2006)



Source: CEC, *Results Report*, Figure 5-2, p. 107

Global recognized that simply reducing natural gas demand from the levels assumed in their modified reference cases to those of Case 3B, 4B, or 5B and rerunning the GPCM model would not properly reflect market forces.[13] GPCM does not endogenously change production pricing curves in the various producing regions as demand for natural gas scales up or down. Rather, the analyst using the model must exercise his or her own judgment to determine how producers might react to a sustained reduction in natural gas demand resulting from an overt governmental policy to induce the development of an electricity industry focused upon high efficiency savings and high renewables development. Global created an approach that would reflect a change in the production and production pricing behavior of producers.

Global focused its attention upon the producing basins in the GPCM model most linked to supplying Western natural gas demand. While natural gas has evolved into a national market, there are producing basins that largely supply one region or another. Once it identified these basins, Global examined the producing behavior characteristic of each basin.

Global developed a lagged producer response to demand reductions relative to the original reference case. In effect, Global determined that the behavior of the producers during the natural gas bubble of the 1980s would be a reasonable model of expected producer behavior under the conditions of Case 5B. Key elements include:

- In recent years, the industry at large has been oriented to developing production, and large cost increases in market price have justified developing expensive fields and pricing gas aggressively.
- Some producers will not recognize a shift in demand or will misunderstand the magnitude of the effect and thus continue with their production development plans even when aggregate gas demand is not up to the levels previously forecast.
- Some producers simply cannot reduce production because of debt service cash flow requirements or fears of permanently reducing total production from a field.

Global modified the production assumptions in GPCM and the producer pricing behavior of the model to reflect this lagged response, leading to a progressively larger overhang of production capacity compared to aggregate demand across all consuming sectors. Global reran the model with these conditions to determine a final set of market clearing prices. The revised analysis using producer adjustments is designated as Case 5B Plus.

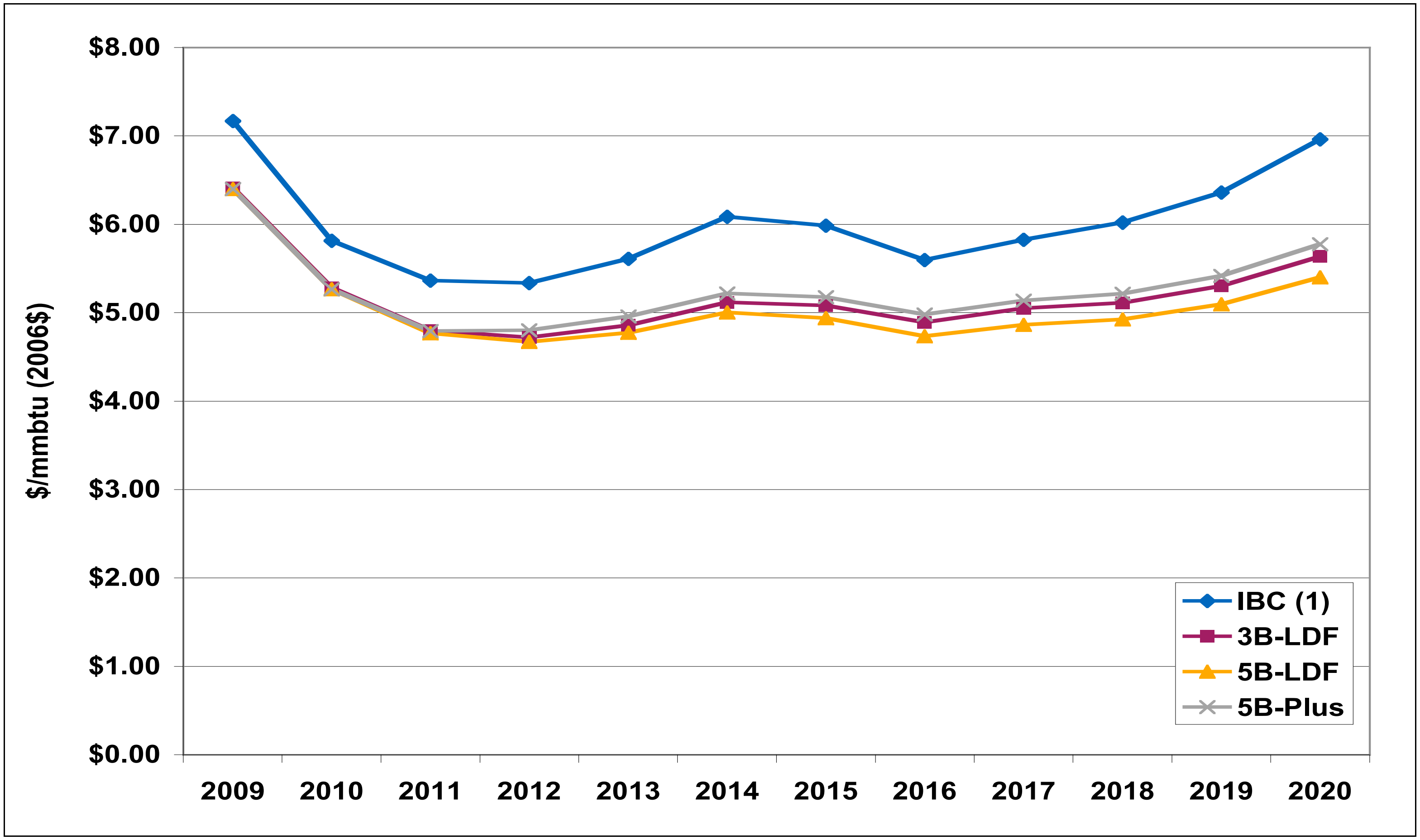
Results

Figure 3 provides the results that Global developed for natural gas market clearing prices, substituting Case 3B and Case 5B natural gas demand for the levels assumed for power generation in the West in its Illustrative Base Case. These two results do not include the impacts of the final step developed by Global in reflecting the behavior of producers, and are therefore incomplete. Case 5B Plus denotes the final market price projections using the complete methodology, e.g., including producer adjustments. Global found a natural gas price reduction averaging about $0.75/mmbtu, but the differential is smaller in earlier years and grows in later years. Case 5B Plus results are about $0.10 – 0.50/mmbtu higher than the Case 5B prices. The smaller end of this range

[13] GPCM is the acronym for the natural gas model used by Global Energy for this project. It is described in detail in Appendix H-1 of the June 2007 *Results Report.*

takes place in early years and the larger end of the range takes place in the later years of the analysis. After a lag, producers have partially reduced production capacity compared to what they would have done in the IBC projections, and this partly mitigates the effects shown for the Case 5B lower demand forecast projections plotted on Figure 3.

Figure 3: IBC, 3B, 5B, and 5B-Plus: Henry Hub Prices ($2006)[1]



Source: Global Energy

Note 1: For Henry Hub forecast, Global uses NYMEX for the first 24 months and then mean reverts for following 24 months to Energy Commission fundamental forecast. For the IBC forecast starting in 2007 for the years affected by NYMEX, an average of the latest available three days were used (for example, December 19–21, 2006).

Stability of Lowered Utility Electric Generation (UEG) Projections

To the extent that end-user price elasticity exists, the various classes of natural gas demand may respond to lower market clearing prices by increasing their consumption compared to the levels assumed in the original analysis, thus taking away at least some of the benefits initially observed. That might sufficiently increase consumption to lead to increased market clearing prices. In practice, several iterations might be necessary to reach a stable price/consumption pattern. To determine whether stable prices were reached, Global reran the electric generation production cost model with the lower prices of Case 5B Plus to determine the size of the demand "rebound." Compared to the Case 5B results reported in the *Scenario Report*, Global found a 1 percent increase in power generation demand in the early years of the simulation and a 2 percent increase in the later years. Under the conditions established for this project—that is, policy-directed installation of preferred resource types with minimal linkage to traditional economic choices by utility executives—this minimal response to lower natural gas prices should be expected. This is a very modest change. In the time frame for this project, it was not possible to modify demand for other classes of end user.

Implications

Some previous studies, investigating the consequences of renewables and finding natural gas price projection reductions of the sort presented above, have taken the next step: use the reduced prices to compute lower production costs for remaining natural gas power generation, or even rate reductions for all end users of natural gas. Such cost reductions have been considered benefits, thus leading to revised conclusions about the costs versus benefits of a high renewable strategy. The CPUC sponsored renewables study by Center for Research Solutions is one such study (refer to footnote 7). The market clearing price effects found therein were large enough to offset the initial cost increases for renewable generation compared to gas-fired generation.

Energy Commission staff has not conducted a complete assessment of the implications of lower gas prices of the sort reported here. No quantitative assessment of benefits of such price reductions is provided here. Policy makers can reasonably assume that there are such benefits, but the magnitude of those benefits should be considered highly speculative. The Wiser study cited in footnote 8 also notes the wide variation in results of the studies reviewed therein. As such, staff believes that a qualitative understanding of some benefits is legitimate, but a quantitative determination of benefits using these scenario project results would be unwarranted.

CHAPTER 4: Conclusions

What has been learned through these supplemental assessments of aging power plant retirement/replacement and implications of lowered natural gas consumption for power generation on natural gas market clearing prices?

The Energy Commission raised aging power plant retirement as a topic in the *2003 IEPR* and adopted an explicit policy position in the *2005 IEPR*. Through the resources of the scenario project, staff and consulting expertise have completed a broad assessment of the retirement of a substantial amount of aging power plants in SCE's transarea. Staff believes that the aging power plant retirement/replacement study, documented in appendices A and B of this report, provides a credible beginning for the evaluation of this extremely complex issue. The results of that study summarized in this overview find variations in the need for thermal capacity replacement capacity needs and transmission upgrades that depend upon the nature of the resource build out that is anticipated. These significant variations mean the problem is more complex and requires considerably more effort than previously understood. That effort must also necessarily involve additional organizations, including the transmission owners, the California ISO, and the generators themselves.

The Energy Commission has a long history of attempting to make accurate natural gas projections, including price projections, which are used in many kinds of economic analyses. In this *2007 IEPR* proceeding, substantial effort has been devoted to scenario assessments and other techniques that better recognize the inherent uncertainty associated with these analyses. One improvement that Staff attempted in this analytic development effort is examining whether results are consistent with the input assumptions that drove those results, i.e. examining feedback loops. Performing the Case 5B Plus analyses is one example of examining these feedback loops. Clearly the Case 5B power generation sector's lower use of natural gas is different than what was assumed in the Illustrative Base Case that determined the IBC price projections. Global gas team developed, in consultation with Staff, a method to take into account gas producer behavior in developing natural gas market clearing prices for this lower level of gas demand. As expected, Global found a price reduction. Global electric team verified that the resulting lower prices had a minimal impact on electric generation, so stability between models has been demonstrated. The size of the projected price reduction necessitates caution before it is used to justify policy decisions. Uncertainties in assumptions and changing conditions are important limitations to all natural gas forecasts. Global's series of forecasts provide a credible foundation on which to continue the quantification of the impact of, and benefits from, replacing gas-fired power with energy efficiency and renewables. If further work on these implications creates greater assurance of the reality of these "benefits," perhaps future IEPR proceedings can rely upon them.

Friday, August 3, 2007

NOTE:

Appendices will be available at a later date.
Please check back on our website after Monday, August 6, 2007.

APPENDIX A:
Analysis of Transmission Implications of Aged Power Plant Retirement and Replacement

APPENDIX B:
Assessment of Production Cost Results of Alternative Aged Power Plant Retirement and Replacement Costs

APPENDIX C:
Impacts On Natural Gas Market Prices of Low Demand for Gas as a Power Generation Fuel In the West

APPENDIX D:
Further Market Analyses for Natural Gas

Webmaster